8 Fuel Assumptions

The EPA Base Case 2004 includes assumptions on coal, natural gas, residual oil, biomass and nuclear fuels. The fuel assumptions described in this chapter pertain to fuel characteristics, fuel market structures, and fuel prices. Coal, natural gas, and biomass price assumptions are represented by fuel supply curves. Using the supply curves, the model endogenously determines coal, natural gas, and biomass prices by balancing the supply and demand for each fuel. In contrast, oil and nuclear fuel prices are exogenously determined and entered into IPM during model set-up as a constant price point which applies to all levels of supply.

8.1 Coal

The coal supply infrastructure implemented in EPA Base Case 2004 consists of 30 aggregated coal supply regions, 41 aggregated demand markets, and transportation links to ship the coal from the supply regions to the demand markets. It represents the coal supply available for electric generation. Section 8.1.1 describes the coal market assumptions in EPA Base Case 2004.

Each aggregated coal supply region has a separate supply curve for each type of coal found in that region. For each type of coal, the curves show the supply of coal available to meet demand at a given price. The regional coal supply curves are differentiated based on coal ranks (i.e., bituminous, subbituminous, and lignite) and sulfur content. Section 8.1.2 summarizes features of the coal supply curves used in EPA Base Case 2004, covers the related topic of coal transportation cost escalation rates, and presents the resulting average mine mouth and delivered price of coal. Section 8.1.3 discusses the update of coal assignments that was incorporated in EPA Base Case 2004. Section 8.1.4 summarizes the coal emission factors used in the base case

8.1.1 Coal Markets

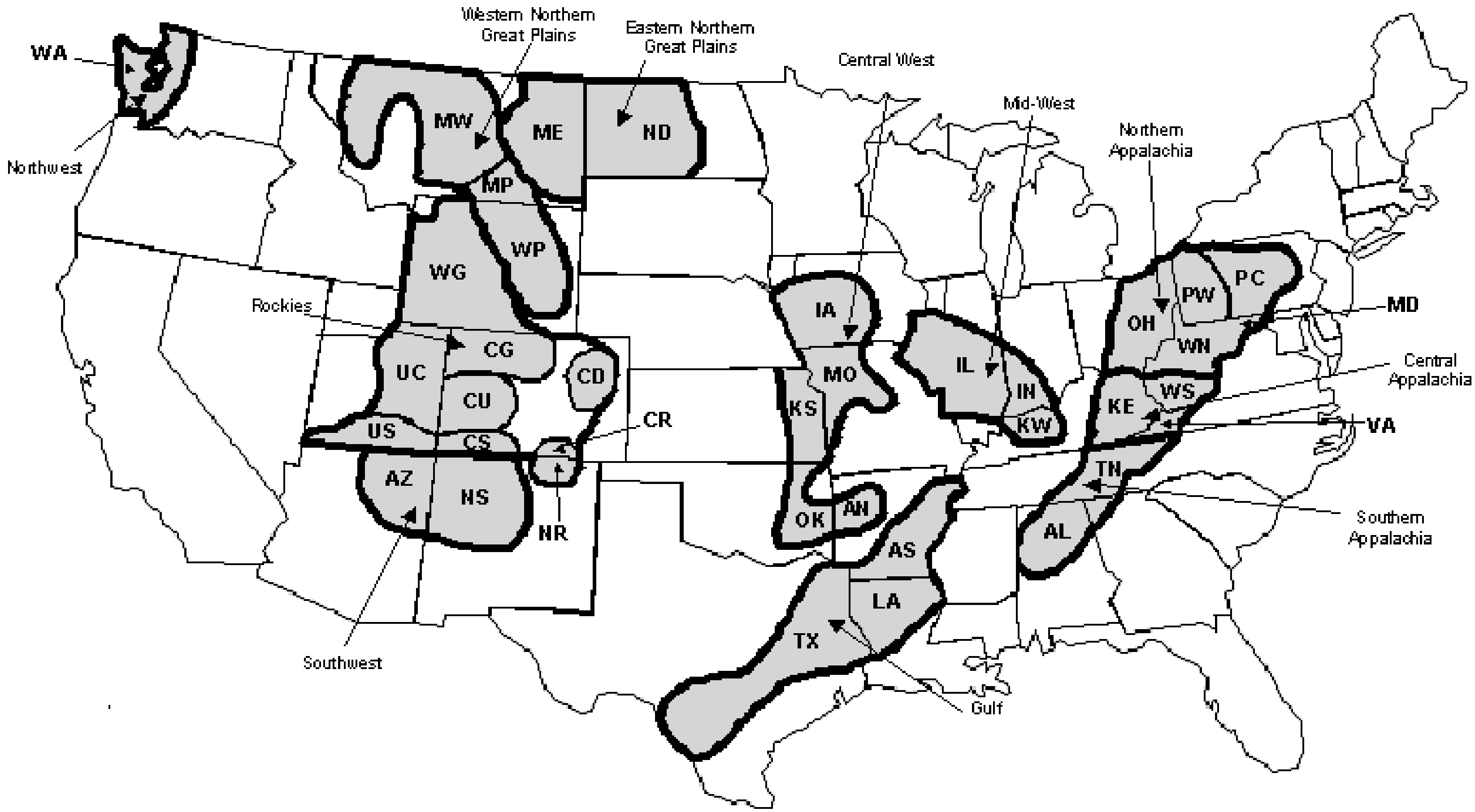
The EPA Base Case 2004 uses coal supply regions and coal demand regions connected by transportation links to model coal markets in IPM. Supply regions represent aggregations of coal-mining areas while the demand regions represent coal plants with similar supply infrastructures within the same geographic area. Transportation links connect the supply and demand regions. A demand region may have transportation links with more than one supply region.

Each coal supply region in the EPA Base Case 2004 contains similar coal-mining areas that supply one or more coal types. Coal supply regions may differ from one another in the types and quality of coal they can supply. Table 8.1 below lists the coal supply regions included in the EPA Base Case 2004. The supply regions are grouped into broad geographically based coal supply areas. Figure 8.1 provides a map showing both the coal supply regions and areas.

Table 8.1. Coal Supply Regions in EPA Base Case 2004

Region	State	Supply Region
Appalachia	Alabama	AL
Appalachia	Kentucky	KE
Appalachia	Maryland	MD
Appalachia	Ohio	OH
Appalachia	Pennsylvania	PC
Appalachia	Pennsylvania	PW
Appalachia	Tennessee	TN
Appalachia	Virginia	VA
Appalachia	West Virginia	WN
Appalachia	West Virginia	WS
Interior	Iowa	IA
Interior	Illinois	IL
Interior	Missouri	MO
Interior	Kansas	KS
Interior	Arkansas	AN
Interior	Arkansas	AS
Interior	Oklahoma	OK
Interior	Indiana	IN
Interior	Kentucky	KW
Interior	Louisiana	LA
Interior	Texas	TX
West	Arizona	AZ
West	Colorado, Denver	CD
West	Colorado, Green River	CG
West	Colorado, Raton	CR
West	Colorado, San Juan	CS
West	Colorado, Uinta	CU
West	Montana	ME
West	Montana	MP
West	Montana	MW
West	New Mexico, Raton	NR
West	New Mexico	NS
West	North Dakota	ND
West	Utah	UC
West	Utah	US
West	Wyoming	WG
West	Wyoming	WP
West	Washington	WA
	Imports	IM

Figure 8.1. Map of the Coal Supply Regions in EPA Base Case 2004



The EPA Base Case 2004 groups coal plants with similar supply infrastructure and within the same geographic area into coal demand region. Table 8.2 lists the coal demand regions that are used in EPA Base Case 2004 and provides a crosswalk between each abbreviation that is used in IPM and a description of the region.

Table 8.2. Coal Demand Regions in EPA Base Case 2004.

Abbreviation	Fuel Demand Region Name
ALRL	Alabama rail plants
AMMM	Arizona and New Mexico mine mouth plants
AMNR	Arizona, New Mexico and Southern Nevada rail plan
GFRL	Arkansas / Louisiana / Mississippi / Houston rail plants
CARL	Carolinas rail plants
CAIN	Central Appalachia Interior Rail Plants
CC	East Colorado plants
IMBG	East Iowa and East Missouri and Illinois River bar
EIMR	East Iowa and East Missouri rail plants
PE	East Pennsylvania
FLBG	Florida barge plants
FLRL	Florida rail plants
GARL	Georgia rail plants
GFBG	Gulf barge plants
IIIR	Indiana, Illinois, West Kentucky Interior rail plants
IIIT	Indiana, Illinois, West Kentucky Interior truck plants
PC	Indina County, Pennsylvania
IBBG	Kentucky, Indiana, Southern Illinois river plants
DALG	Lignite Dakotas plant
TXLG	Lignite Louisiana and Texas
MIBG	Michigan Upper Penninsula barge plants
MNRL	Minnesota rail plants
WTXR	N. and W. Texas rail plants
NE	New England / Hudson River plants / Hudson plant
NORL	North Ohio rail plants
NIIR	Northern Indiana and Illinois rail plants
ORPB	Pennsylvania-Ohio River plants
PRB	PRB plants
MARL	South PJM Rail plants
MABG	South PJM-VEPCO Barge plants
TKIN	Tennessee and Kentucky interior plants
TABG	Tennessee and Northern Alabama river plants
NU	Upstate New York plants
VEPR	VEPCO rail plants
MWRL	W Iowa / W Missouri / Kansas / Nebraska / NW Oklahoma rail
WONR	Washington / Oregon / N. Nevada rail plants
CU	West Colorado and Utah plants
WOMR	West Ohio and Michigan rail plants
NAIN	Western Pennsylvania / Northern West Virginia
WIRL	Wisconsin rail plants
WYGR	Wyoming Green River plants

8.1.2 Coal Supply Curves, Transportation Escalation Rates, and Mine Mouth Prices

There is a unique coal supply curve for each IPM coal supply region (shown in Table 8.1), coal type (shown in Table 8.7) present within that region, and model run year. These supply curves describe the relationship between the coal supply and the mine-mouth price of coal. They capture how coal mine-mouth prices change with the quantities demanded. The coal supply curves take into account the coal resource base, supply costs, and coal supply productivity.

EPA Base Case 2004 retains the coal-supply curves and transportation cost assumptions used in EPA Base Case 2003 (v.2.1.6). These curves incorporate the percent change in labor productivity assumed in AEO 2003, which were developed through expert judgement based on historic experience and derived from the data reported in Form EIA-7A Coal Production Report. The productivity assumptions are shown in the Appendix 8-1. To incorporate the AEO productivity assumptions in EPA Base Case 2004, AEO and IPM coal supply regions were first matched up. Then, the AEO 2003 data for each coal supply region were used to derive the percentage change in labor productivity between each of the model run years in EPA Base Case 2004 (i.e., 2007 to 2010, 2010 to 2015, and 2015 to 2020). Finally, these calculated percentage changes in labor productivity were incorporated into the EPA Base Case coal supply curves for each region.

Under these assumptions, the market price of coal in the EPA Base Case 2004 is determined endogenously in IPM: it is the price at which the supply of a specific type of coal from a specific coal supply region satisfies the demand in a specific model run year. The market price for coal is specific to each supply region and coal type combination, i.e., all plants purchasing the same coal type from a supply region face the same mine-mouth market-clearing price. Table 8.3 below summarizes the average mine-mouth market-clearing prices that resulted under EPA Base Case 2004. Prices are shown for coal supply areas in each model run year. They are averaged across the constituent coal supply regions (in Table 8.1) and coal types (in Table 8.7).

Table 8.3. Average Mine-Mouth Coal Prices (1999$/ton) in the EPA Base Case 2004

	2007	2010	2015	2020
Appalachia	$22.21	$21.39	$21.31	$20.46
Interior	$14.82	$14.11	$13.08	$12.19
West	$6.67	$6.82	$6.80	$6.47
National Average	$12.74	$12.24	$11.85	$10.84

The mine-mouth market-clearing price does not include transportation costs incurred in moving the coal between the supply regions and demand regions. Each transportation link between a coal demand and supply region is provided a transportation cost based on the distance and mode of transport for that link. The coal transportation cost escalation assumptions in EPA Base Case 2004 are presented in Table 8.4. The percentage changes in coal transportation cost rates between EPA Base Case 2004 model run years match the percentage changes in transportation costs for corresponding years in AEO 2003. The AEO coal transportation cost escalation rates are based on “projected variations in reference case fuel costs, labor costs, the user cost of capital for transportation equipment, and time trend.”

Table 8.4. Transportation Rate Multipliers, Years 2001-2025, in EPA Base Case 2004

Year	Reference Case
2001	1.0000
2002	0.9914
2003	0.9783
2004	0.9622
2005	0.9661
2006	0.9609
2007	0.9526
2008	0.9455
2009	0.9376
2010	0.9304
2011	0.9241
2012	0.9134
2013	0.9014
2014	0.8892
2015	0.8739
2016	0.8587
2017	0.8440
2018	0.8282
2019	0.8127
2020	0.7954
2021	0.7864
2022	0.7773
2023	0.7673
2024	0.7577
2025	0.7487

The delivered coal price is the sum of the transportation costs and the mine-mouth market-clearing price. Table 8.5 below provides a summary of the national average mine-mouth coal price and delivered coal prices that resulted under the EPA Base Case 2004.

Table 8.5. National Average Mine-Mouth and Delivered Coal Prices in the EPA Base Case 2004 (1999$/mmBtu)

	2007	2010	2015	2020
Mine-mouth Price (U.S. Average)	$0.61	$0.58	$0.56	$0.52
Delivered Price (U.S. Average)	$1.08	$1.05	$1.01	$0.96

8.1.3 Coal Assignments

For EPA Base Case 2004, EPA obtained technical input from recognized coal experts at PA Consulting, Inc. (PA), to perform a major review of the coal choices offered to the specific generating units represented in EPA's application of IPM. Updates were made to coal assignments to enable the model to better capture recent developments in the use of coal.

The ranks of coal offered to specific generating units were initially determined by ICF Consulting, Inc. based on a detailed review of historical EIA Form 423 and Form 767 plant-level coal consumption data.

ICF then applied the procedure detailed in section 3.9.1 to determine the grades of coal (differentiated by sulfur content) offered to each generating unit in EPA Base Case 2004.

PA reviewed the resulting assignments for consistency with recent practices. Particular attention was given to the assignment of sub-bituminous Powder River Basin (PRB) coal to coal-fired generating units, since significant changes have been occurring in this area in recent years. In their review of PRB coal assignments, PA identified units not currently burning PRB coal, units currently burning 100% PRB coal, units that currently blend (or have blended) PRB coal, units that have tested PRB coal, units that have announced plans to test PRB coal, units that are known to have an interest in testing PRB coal, and units that are good economic candidates for PRB coal.

The data sources used for this review included FERC Form 423 and EIA-423 data (as reported in Platts CoalDat database), trade press reports, and PA's own industry knowledge. For example, units currently burning 100% PRB coal, units that currently blend (or have blended) PRB coal, and units that have tested PRB coal were identified primarily based on current and historical FERC Form 423 or EIA-423 data, although PA's industry knowledge played a role in some cases. For example, PA was aware that FERC Form 423 does not reflect use of PRB coal by certain TVA plants so recommended giving these units PRB coal as a fuel choice. Units not currently burning PRB coal, units that have announced plans to test PRB coal, units that are known to have an interest in testing PRB coal, and units that are good economic candidates for PRB coal were identified primarily based on trade press reports and PA's industry knowledge.

As a result of this review and a subsequent evaluation by ICF and EPA, the following changes were made:

- Based on information showing that they were currently burning or previously had burned PRB subbituminous coal (either 100% or in a blend) or had announced plans to test PRB coal, fifty generating units, not previously assigned PRB coal were given PRB subbituminous coal as a fuel option. Subbituminous coal was allowed to be burned at lignite boilers only if it was already being used.
- PRB coal was given as a fuel option for an additional 23 generating units that PA's analysis indicated were good economic candidates for PRB coal. Units were included based on a variety of data sources, including trade press reports, available presentations and reports by coal producers, users and consultants, and PA's analytical work for private clients.
- PRB coal was dropped as a fuel option for six generating units, known to be unlikely to use PRB coal in the future. Examples include Georgia Power's Wansley plant (where test burns of PRB coal were unsuccessful), the Wyandotte plant in Michigan (which has publicly announced that it will not use PRB coal), and AEP's Mountaineer plant in West Virginia (where a decision was recently made to retrofit a scrubber and use local high-sulfur coal rather than continuing the use of PRB coal over the long term).

Examples of the resulting coal assignments are shown in Table 8.6.

Table 8.6. Example of Coal Assignments made in EPA Base Case 2004

Entry ID	Plant Name	Unique ID	SIP SO_2 Limit (lbs/MMBtu)	Scrubber?	Fuels Allowed
1	Salem Harbor	1626_B_1	1.2	No	BA BB
2	Dickerson	1572_B_3	1.5	No	BA BB BD
3	Glen Lyn	3776_B_51	2.6	No	BA BB BD BE
4	Danskammer	2480_B_3	3.8	No	BA BB BD BE BF

5	R E Burger	2864_B_5	9.0	No	BA BB BD BE BF BG
6	Mountaineer	6264_B_1	3.2	Yes	BG BF BE BD
7	Big Brown	3497_B_1	3.0	No	LD LE SB SD SE
8	Minnesota Valley	1918_B_4	4.0	No	BA BB BD BE BF SB SD SE
9	E D Edwards	856_B_1	4.7	No	BA BB BD BE BF SB
10	R Gallagher	1008_B_1	4.7	No	BA BB BD BE BF SB

8.1.4 Emission Factors

The EPA Base Case 2004 uses emission factors to represent the SO_2, CO_2, and mercury content of coal. The emission factors describe the ratio of the specific emission to the energy contained in the coal and represent the out-of-stack emissions that would occur if the fuel were combusted at a facility and no reductions occurred at the facility. The EPA Base Case 2004 retains the assumptions for the sulfur and carbon emission factors used in previous EPA base cases. As discussed in detail in section 5.3.1, the mercury emissions assumptions in EPA Base Case 2004 are based upon EPA's Information Collection Request that was completed in 2000.

Sulfur Dioxide

EPA Base Case 2004 uses 6 different sulfur grades of bituminous coal, 3 different grades of subbituminous coal, and 3 different grades of lignite to represent the emission factor for coal. The sulfur grades capture the variations in sulfur content of the different types of coal. Table 8.7 below lists the different sulfur grades used in the EPA Base Case 2004.

Table 8.7. SO_2 Emission Factors of Coal Used in the EPA Base Case 2004

Coal Grade Designation in the EPA Base Case 20004	Sulfur Dioxide (lbs./mmBtu)
Bituminous	
Low Sulfur Bituminous (Western) (BB)	1.0
Low Sulfur Bituminous (Eastern) (BA)	1.1
Low Medium Sulfur Bituminous (BD)	1.5
Medium Sulfur Bituminous (BE)	2.2
Medium High Sulfur Bituminous (BF)	3.0
High Sulfur Bituminous (BG)	5.0
Subbituminous	
Low Sulfur Subbituminous (SB)	1.0
Low Medium Sulfur Subbituminous (SD)	1.4
Medium Sulfur Subbituminous (SE)	2.1
Lignite	
Low Medium Sulfur Lignite (LD)	1.4
Medium Sulfur Lignite (LE)	2.1
Medium High Sulfur Lignite (LF)	2.9

The SO_2 emission factors shown in Table 8.7 are used in three ways. First, for model plants representing existing unscrubbed coal steam units, the emission factors are compared to the applicable unit-level regulatory SO_2 emission rates (discussed in section 3.9.1) to determine which coal grades the model plant is allowed to burn in order to remain within its unit-specific regulatory emission rate limit. Second, the removal rate for existing scrubbed units (i.e., those units which entered the modeling time horizon with pre-existing scrubbers) is calculated from the unit's historical emission rate as contained in the NEEDS data base and the emission factor (shown in Table 8.7) for the predominant coal grade burned at the unit. Third, for all model plants representing coal steam units — whether existing or new, unscrubbed or scrubbed — the SO_2 emission factors shown in Table 8.7 are used to determine SO_2 emissions. The emission factors are scaled proportionately for model plants representing existing unscrubbed coal steam units with average historical emission rates (derived from the NEEDS database) of 0.8 lbs/mmBtu or less. Whether the emission factors are scaled or used directly as shown in Table 8.7, SO_2 emissions are obtained by multiplying the total consumption of each coal type (on a heat content basis, i.e., in mmBtu) for the period covered (e.g., annual) by the associated emission factor (in lbs/mmBtu). The result is the uncontrolled mass emissions (in lbs or tons) from each fuel type. Summing across all fuel types yields the total uncontrolled mass SO_2 emissions. If the model plant has SO_2 controls, the applicable removal rate is applied to obtain the total SO_2 mass emissions after scrubbing. (The SO_2 removal rate for new units is shown in Table 3.13 and for retrofits of existing units in Table 5.2. The removal rate for existing scrubbed units is calculated as described above.) System-wide emissions on a tonnage basis are then obtained by summing SO_2 mass emissions from all model plants. A model plant's emission rate (in lbs/mmBtu) for a specific period (e.g., a year) is calculated by dividing its total SO_2 mass emissions by the total coal of all types consumed on a heat content basis (i.e., in mmBtu) in the period.

Nitrogen Oxides

NO_X emission rates do not vary with fuel but are dependent on the combustion properties in the generating unit. They are therefore not treated here but in sections 3.9.2, Table 3.13, and section 5.2.

Carbon Dioxide

The emission factor for CO_2 describes the emissions of CO_2 per unit of energy in coal. It represents the amount of out-of-stack emission that would occur if the coal were combusted at a generating facility. Table 8.8 below summarizes the assumptions on the CO_2 emission factors for the three coal grades in EPA Base Case 2004.

Table 8.8. Carbon Dioxide Emission Factors in EPA Base Case 2004

Fuel	Carbon Dioxide (lbs/mmBtu)
Bituminous Coal	205.3
Subbituminous Coal	212.7
Lignite	215.4

Mercury

Section 5.3.1 contains a detailed description of the assumptions in EPA Base Case 2004 regarding the mercury content of coal. For each coal sulfur grade in the EPA Base Case 2004, there are up to 3 mercury emission factors that characterize the mercury content for that grade of coal. Table 8.9 below provides a summary of the mercury emission factors in the EPA Base Case 2004. Each supply region producing a specific coal grade is assigned one of the listed emission factors, i.e, the one that most closely reflects the mercury content of its coal. Section 5.3.1 describes the methodology that was used in developing the mercury emission factors shown in Table 8.9 from data obtained under EPA's 1998-2000 "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions."

Table 8.9. Mercury Emission Factors in the EPA Base Case 2004

Coal Type by Sulfur Grade	Mercury Emission Factors by Coal Sulfur Grades (lbs/TBtu)		
	Emission Factor #1	Emission Factor #2	Emission Factor #3
Low Sulfur Eastern Bituminous (BA)	3.69	5.17	--
Low Sulfur Western Bituminous (BB)	3.41	4.1	7.85
Low Medium Sulfur Bituminous (BD)	5.07	12.54	21.95
Medium Sulfur Bituminous (BE)	6.08	10.45	18.42
Medium High Sulfur Bituminous (BF)	6.83	11.09	18.69
High Sulfur Bituminous (BG)	8.04	17.43	28.73
Low Sulfur Subbituminous (SB)	4.55	5.88	7.06
Low Medium Sulfur Subbituminous (SD)	4.4	6.01	7.39
Medium Sulfur Subbituminous (SE)	4.61	6.45	10.71
Low Medium Sulfur Lignite (LD)	8.45	--	--
Medium High Sulfur Lignite (LF)	5.88	9.79	–

8.2 Natural Gas

The EPA Base Case 2004 uses supply curves to model natural gas supply. EPA and ICF Consulting, Inc. performed a major review and update of the natural gas supply curves for EPA Base Case 2004. A detailed description of the update is provided in Section 8.2.1. The updated gas supply curves were generated using ICF Consulting Inc.'s North American Natural Gas Analysis System (NANGAS) model to provide a price-quantity relationship for the natural gas supply in the United States. The supply curves in EPA Base Case 2004 incorporate the impact on prices of demand for natural gas from the non-electric sector. A separate supply curve was developed for each model run year in the base case.

8.2.1 Description of Update

On October 23-24, 2003 EPA convened a panel of eight prominent, independent experts for a peer review of the natural gas assumptions used in EPA's applications of IPM. Detailed background material on the peer review can be found at the following EPA web site: **www.epa.gov/airmarkets/epa-ipm/.** In addition, on November 19, 2003 EPA and ICF Consulting, Inc. were given a briefing by industry and government representatives on the modeling methods, data usage, and results of the National Petroleum Council's 2003 Natural Gas Study. EPA subsequently obtained detailed supply and demand data from the NPC study. These were used to calibrate and update assumptions underlying the gas supply curves that were developed for EPA Base Case 2004.

As a result of the peer review and data obtained from the NPC study, a completely new set of natural gas supply curves was produced for use in EPA Base Case 2004. The new supply curves reflect the following changes.

Resource Data and Reservoir Description: A complete update to the undiscovered natural gas resource base for the Western Canada Sedimentary Basin (WCSB) and key regional updates within the U.S. were completed as new data became available in years 2002 and 2003. For the U.S., the primary data sources were the United States Geological Survey (USGS) and Minerals Management Service (MMS). ICF investigated the conventional resource assessment of the Canadian Gas Potential Committee (CGPC), unconventional resource assessments published by the Alberta Energy Utilities Board (AEUB), publicly available reports, and information available from the provincial energy departments for Saskatchewan and British Columbia. Key updates included:

- Reviewing assumptions regarding conventional resource plays and, where warranted, modifying the internal field size distribution procedure so that the maximum undiscovered field size did not exceed the maximum undiscovered field size class estimates of the USGS for corresponding assessment units.
- Reducing well spacing assumptions to reflect current production practices.
- Where new data were available, updating reservoir parameters like average depth, gas composition and impurities, and percent of federal land in play.
- Comparing and calibrating modeled production trends in the Rocky Mountain and Gulf Coast regions with recent established history, using regional natural gas production reports from Lippman Consulting, Inc.
- Substantially re-categorizing and updating undiscovered Canadian resources based on recent estimates published by CGPC, including a complete update of undiscovered resources for established plays in the Western Canadian Sedimentary Basin.

Treatment of Frontier Resources: Using a variety of recent publicly available data sources, ICF updated the representation of Alaska North Slope, Mackenzie Delta, Sable Island, and existing and potential liquified natural gas (LNG) terminals in the North American Natural Gas Analysis System (NANGAS), the model used to generate the natural gas supply curves for EPA Base Case 2004.

Exploration and Production (E&P) Characterization: Among the key revisions in E&P characterization that resulted from the peer review process were:

- Increasing the required rate of return (hurdle rate) from 10% to 15% for exploration projects and 12% for development projects.
- Setting success rate improvement assumptions of 0.5% per year for onshore projects and 0.8% per year for offshore projects.
- Establishing operating cost decline rates of 0.54% per year and drilling cost decline rates of 1.9% per year for onshore and 1.2% per year for offshore.
- Making use of the research and development (R&D) program evaluation undertaken by the U.S. Department of Energy's Strategic Center for Natural Gas to identify key technology levers and advancement rates.

Natural Gas Demand: Based on the peer review recommendations the following improvements were made to the representation of end use demand for natural gas:

- Capturing demand destruction in the industrial feedstock sector by incorporating into NANGAS the natural gas demand forecasts for the feedstock and process heat sectors developed for the NPC natural gas study.
- Revising the macroeconomic equations for residential and commercial sector demand for natural gas and capturing income elasticity in the representation of residential demand.

These updates of the natural gas supply assumptions resulted in the new natural gas supply curves, transportation differentials, and seasonal adders which are discussed in the following sections. A technical background paper, prepared by ICF Consulting, Inc., on the development of the natural gas supply curves for EPA Base Case 2004 is included in Appendix 8-2.

8.2.2 Henry Hub Prices

EPA Base Case 2004, v.2.1.9, uses supply curves to provide a price-quantity relationship for natural gas supplies in the United States. The gas supply curves (presented in data format in Appendix 8-3) were derived using the North American Natural Gas Analysis System (NANGAS), a detail-rich natural gas model developed by ICF Consulting, Inc. Curves representing total gas supply and non-electric sector demand are produced through a series of NANGAS model runs, where natural gas supply, demand, and transportation are equilibrated under a variety of electricity growth rate assumptions. These are used to derive gas supply curves for the electric sector. A separate supply curve is provided for each IPM model run year.

The supply curves in Appendix 8-3 specify annual price and volume relationships at the Henry Hub[1]. For each listed step the price applies for all increments of supply greater than the value shown in the preceding step up to and including the supply level indicated in the current step.

8.2.3 Transportation Differentials

The EPA Base Case 2004 includes explicit transportation differentials to reflect the cost of moving the gas to the plant. Table 8.10 below shows the transportation differentials for each IPM model region relative to the Henry Hub price. These transportation adders were produced by analyzing daily gas price data for key pricing points in North America as reported in the Platts publication "Gas Daily". A charge of 22 cents/mmBtu in NYC and CALI and 7 cents/mmBtu in all other regions, were included in the values shown in Table 8.10 to capture Local Distribution Company (LDC) transportation charges from the city gate. The key natural gas pricing points were mapped into IPM regions to produce the average annual differentials that appear in these tables.

8.2.4 Seasonal Price Adders

EPA Base Case 2004 includes explicit seasonal adders, which are applied relative to the Henry Hub price obtained from the gas supply curves to account for the seasonality in gas prices. Table 8.11 below shows the seasonal gas adders used in EPA Base Case 2004. The values were derived from daily price data for key pricing points as reported in the Platts (McGraw-Hill) publication "Gas Daily". These seasonal adders are used to distinguish summer and winter delivered gas prices. Seasonal gas adders vary by IPM model region. In general, seasonal gas adders for winter are higher than those for summer. In winter, due to lower temperatures, there is higher demand for gas by the residential sector for space heating. This results in higher gas pipeline utilization and higher delivered gas prices. The appearance of negative values in Table 8.11 means that based on the "Gas Daily" data, the price of gas (without consideration of the Transportation Differentials captured in Table 8.9) is projected to be lower than the Henry Hub price by the amount shown for the indicated region in the specified season.

[1]The Henry Hub is a gas pipeline junction in Louisiana, which interconnects with nine interstate and four intrastate pipelines and offers shippers access to pipelines that have markets in U.S. Gulf Coast, Southeast, Midwest, and Northeast regions. Due to the Hub's strategic centralized location, the price of natural gas at the Henry Hub serves as the generally accepted reference point for U.S. natural gas trading.

Table 8.10. Natural Gas Transportation Differentials for EPA Base Case 2004

	MECS	ECAO	ERCT	MACE	MACW	MACS	WUMS	MANO	MAPP	UPNY	DSNY	NYC	LILC
2007	20.40	26.10	-5.00	38.60	43.40	38.60	15.60	16.60	-10.00	24.20	39.50	86.00	47.20
2010	20.40	26.10	-5.00	38.60	43.40	38.60	15.60	16.60	-10.00	24.20	39.50	86.00	47.20
2015	20.40	26.10	-5.00	38.60	43.40	38.60	15.60	16.60	-10.00	24.20	39.50	86.00	47.20
2020	20.40	26.10	-5.00	38.60	43.40	38.60	15.60	16.60	-10.00	24.20	39.50	86.00	47.20

	NENG	FRCC	VACA	TVA	SOU	ENTG	SPPN	SPPS	CALI	PNW	AZNM	RMPA	NWPE
2007	43.40	36.70	45.30	10.80	8.90	8.90	-12.00	-10.00	37.20	-29.00	-8.00	-27.00	-40.00
2010	43.40	36.70	45.30	10.80	8.90	8.90	-12.00	-10.00	37.20	-29.00	-8.00	-27.00	-40.00
2015	43.40	36.70	45.30	10.80	8.90	8.90	-12.00	-10.00	37.20	-29.00	-8.00	-27.00	-40.00
2020	43.40	36.70	45.30	10.80	8.90	8.90	-12.00	-10.00	37.20	-29.00	-8.00	-27.00	-40.00

Table 8.11. Seasonal Natural Gas Price Adders in EPA Base Case 2004

Winter	MECS	ECAO	ERCT	MACE	MACW	MACS	WUMS	MANO	MAPP	UPNY	DSNY	NYC	LILC
2007	0.00	1.91	-1.90	5.74	5.74	4.78	1.91	1.91	2.87	3.83	7.65	7.65	9.57
2010	0.00	1.91	-1.90	5.74	5.74	4.78	1.91	1.91	2.87	3.83	7.65	7.65	9.57
2015	0.00	1.91	-1.90	5.74	5.74	4.78	1.91	1.91	2.87	3.83	7.65	7.65	9.57
2020	0.00	1.91	-1.90	5.74	5.74	4.78	1.91	1.91	2.87	3.83	7.65	7.65	9.57

Summer	MECS	ECAO	ERCT	MACE	MACW	MACS	WUMS	MANO	MAPP	UPNY	DSNY	NYC	LILC
2007	0.00	-2.90	2.87	-7.70	-7.70	-6.70	-1.90	-2.90	-3.80	-5.70	-7.70	-10.50	-10.50
2010	0.00	-2.90	2.87	-7.70	-7.70	-6.70	-1.90	-2.90	-3.80	-5.70	-7.70	-10.50	-10.50
2015	0.00	-2.90	2.87	-7.70	-7.70	-6.70	-1.90	-2.90	-3.80	-5.70	-7.70	-10.50	-10.50
2020	0.00	-2.90	2.87	-7.70	-7.70	-6.70	-1.90	-2.90	-3.80	-5.70	-7.70	-10.50	-10.50

Winter	NENG	FRCC	VACA	TVA	SOU	ENTG	SPPN	SPPS	CALI	PNW	AZNM	RMPA	NWPE
2007	7.65	-5.70	7.65	0.00	-1.00	0.00	0.96	0.96	-3.80	10.52	0.00	8.61	22.96
2010	7.65	-5.70	7.65	0.00	-1.00	0.00	0.96	0.96	-3.80	10.52	0.00	8.61	22.96
2015	7.65	-5.70	7.65	0.00	-1.00	0.00	0.96	0.96	-3.80	10.52	0.00	8.61	22.96
2020	7.65	-5.70	7.65	0.00	-1.00	0.00	0.96	0.96	-3.80	10.52	0.00	8.61	22.96

Summer	NENG	FRCC	VACA	TVA	SOU	ENTG	SPPN	SPPS	CALI	PNW	AZNM	RMPA	NWPE
2007	-7.70	5.74	-9.60	0.00	0.00	0.00	0.00	-1.00	4.78	-13.40	0.00	-12.40	-26.80
2010	-7.70	5.74	-9.60	0.00	0.00	0.00	0.00	-1.00	4.78	-13.40	0.00	-12.40	-26.80
2015	-7.70	5.74	-9.60	0.00	0.00	0.00	0.00	-1.00	4.78	-13.40	0.00	-12.40	-26.80
2020	-7.70	5.74	-9.60	0.00	0.00	0.00	0.00	-1.00	4.78	-13.40	0.00	-12.40	-26.80

8.2.5 Wellhead and Delivered Prices

In EPA Base Case 2004, market clearing prices are determined endogenously by equilibrating supply and demand. The previously described supply curves along with transportation and seasonal cost adders all enter into the calculations of total expenditures on natural gas consumption for electric generation. Table 8.12 below provides a summary of the wellhead and national average delivered price resulting under EPA Base Case 2004.

Table 8.12. US Wellhead and National Average Delivered Natural Gas Prices in the EPA Base Case 2004 (1999 $/mmBtu)

Year	Wellhead Gas Price (at Henry Hub)	Delivered Gas Price
2007	3.20	3.35
2010	3.20	3.34
2015	3.25	3.42
2020	3.16	3.33

8.2.6 Emission Factors

EPA Base Case 2004 includes emission factor assumptions for CO_2 and mercury in natural gas. The emission factors specify the out-of-stack emission that would result from combusting natural gas in electric generation facilities without any controls. For the emission factor of CO_2 in natural gas, the EPA Base Case 2004 retains the assumption of 117 lbs/mmBtu. The EPA Base Case 2004 also includes the assumption that the emission factor of mercury in natural gas is 0.00014 lbs/Tbtu, based on an earlier EPA study.[2]

8.3 Fuel Oil

8.3.1 Supply Assumptions

Unlike coal, natural gas and biomass prices, which are derived endogenously in EPA Base Case 2004, fuel oil prices are stipulated exogenously. The fuel oil price assumptions used in EPA Base Case 2004 are derived from crude oil prices in EIA's Annual Energy Outlook 2004. The AEO 2004 crude oil prices are reproduced in Table 8.13 for the two model regions: Mid-Atlantic Area Council - East (MACE) and New England Power Pool (NENG). Under the EPA Base Case 2004, these are the only regions where fuel oil is offered as an option for oil/gas steam boilers.

Table 8.13. Fuel Oil Prices in EPA Base Case 2004

High Sulfur Resid Prices by IPM Region 1999$/mmBtu		
	IPM Region	
Year	MACE	NENG
2007	3.51	2.93
2010	3.57	2.98
2015	3.67	3.11
2020	3.76	3.22

[2]Analysis of Emissions Reduction Options for the Electric Power Industry," Office of Air and Radiation, US EPA, March 1999.

Low Sulfur Resid Prices by IPM Region 1999$/mmBtu		
	IPM Region	
Year	MACE	NENG
2007	3.73	3.30
2010	3.79	3.35
2015	3.89	3.47
2020	3.99	3.58

Distillate Prices by IPM Region 1999$/mmBtu		
	IPM Region	
Year	MACE	NENG
2007	4.72	4.80
2010	4.85	4.94
2015	5.23	5.29
2020	5.58	5.6

8.3.2 Emission Factors

The emission factors for fuel oil describe the SO_2, CO_2 and mercury content per unit of energy in the fuel oil. In the EPA Base Case 2004, these factors represent the emissions that would occur if the fuel oil were combusted and no reduction occurred at the facility.

Sulfur Dioxide

The EPA Base Case 2004 includes three different residual fuel oil grades. The three grades are differentiated based on their sulfur content. The SO_2 emission factors, as seen in Table 8.14, are consistent with AEO 2004.

Table 8.14. Sulfur Dioxide (SO_2) Content of Fuel Oils in EPA Base Case 2004

Fuel	SO_2 Content
High Sulfur Residual	2.69 lb/mmBtu.
Low Sulfur Residual	1.08 lb/mmBtu
Distillate	0.0 lb/mmBtu

Carbon Dioxide

EPA Base Case 2004 assumes the CO_2 emission factor for fuel oil to be 173.9 lbs/mmBtu.

Mercury

EPA Base Case 2004 assumes a mercury emission factor of 0.48 lb/TBtu for all fuel oils, regardless of sulfur content.

8.4 Biomass

Biomass is offered as a fuel for existing dedicated biomass plants and potential biomass gasification combined cycle under the EPA Base Case 2004. In addition to these plants, it is also offered to all coal-fired power plants under policy cases that include biomass co-firing . Biomass fuel supply curves were developed for EPA Base Case 2004 from the biomass fuel supply and price data in EIA's AEO 2001.

8.4.1 Market Structure

Consistent with the biomass fuel data and structure of EIA's AEO 2001, EPA Base Case 2004 utilizes thirteen regional biomass fuel supply curves, one for each of the 13 National Energy Modeling System (NEMS) regions represented in AEO 2001. Plants demand biomass from the supply curve corresponding to the NEMS region in which they are located. No inter-regional trading of biomass occurs. Each biomass supply curve depicts the price-quantity relationship for biomass and varies over time. There is a separate curve for each model run year. The supply component of the curve represents the aggregate supply in a region of four types of biomass fuels: forestry residue, agricultural residue, urban wood waste and mill residue and energy crops. The price component of the curve includes transportation cost and represents delivered fuel cost at the plant gate. The original AEO 2001 supply curves contained 50 price steps. For computational efficiency, this has been reduced to 8 or 9 prices steps (depending on region) in the biomass supply curves used in EPA Base Case 2004. Appendix 8-4 contains a table which provides a consolidated summary of the 2010 base case biomass supply curves for the 13 regions.

Biomass prices in EPA Base Case 2004 are derived endogenously based on the aggregate demand for biomass in each region. They represent market-clearing prices. There is a unique market-clearing price for each supply region and all plants using biomass from that supply region face the same market-clearing price.

8.4.2 Emission Factors

The EPA Base Case 2004 models SO_2 and mercury emissions from biomass combustion using biomass emission factors. The combustion of biomass fuel is considered to have a net zero impact on atmospheric carbon dioxide levels since the emissions released are equivalent in carbon content to the carbon absorbed during fuel crop growth.[3]

Sulfur Dioxide
The biomass SO_2 emission factor in EPA Base Case 2004 is 0.08 lbs/mmBtu[4].

Mercury
Based on an earlier EPA analysis, the EPA Base Case 2004 includes the assumption that mercury emission factor of wood waste is 0.57 lbs/TBtu.[5]

8.5 Nuclear Fuel

EPA Base Case uses the AEO 2004 nuclear fuel price (1999$) forecast of $0.41/mmBtu for the 2007-2022 modeling horizon.

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[3] Hughes, E., "Role of Renewables in Greenhouse Gas Reduction," Electric Power Research Institute (EPRI): November, 1998. Report TR-111883, p. 28.
[4] Biomass Co-firing", Chapter 2 in "Renewable Energy Technology Characterizations", U.S. Department of Energy and Electric Power Research Institute (EPRI), 1997.
[5] Analysis of Emissions Reduction Option for the Electric Power Industry," Office of Air and Radiation, US EPA, March 1999.